Determination of The Best Foam Injection Strategy in Ensuring High Hydrocarbon Recovery

by

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13574

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Bandar Seri Iskandar

31750

Perak Darul Ridzuan

CERTIFICATION OF APPROVAL

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Approved by,

____

(Dr Sonny Irawan)

UNIVERSITI TEKNOLOGI PETRONAS
TRONOH, PERAK
MAY 2014

CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

(MOHD EMIR BIN ISMAIL)

ABSTRACT

Foam injection is one of the available Enhanced Oil Recovery (EOR) techniques in recovering the residual oil saturation after the application of the secondary recovery techniques. Foam injection makes use of the presence of the foam in the reservoir. In the case where gas is injected without the presence of foam, the mobility of the gas is high. This will lead to viscous fingering and gravity override of the gas. With the addition of the foam to the gas injection, the mobility of the gas will be low, minimizing the intensity of the viscous fingering and gravity override.

The generation of the foam, stability, and the effectiveness of the foam injection will be depending on how the foam is being injected into the reservoir. So, the objective of this project is to determine the best foam injection strategy. Precisely, we will be focusing on the details of the foam injection operation such as the surfactant concentration and injection rate along with when the injection to be carried out after a period of natural production (primary recovery).

In order to complete this task, we will be using ECLIPSE reservoir simulator to simulate the production performance of the reservoir model for several cases of foam injection. The cases will be varying according to foam concentrations and foam injection rates.

ACKNOWLEDGEMENT

Firstly I would like to thank God Almighty for with His blessings I am able to successfully complete this project along with the report. I would also like to express my appreciation and gratefulness to my Final Year Project supervisor, Dr. Sonny Irawan for his guidance and time from the start of this project until now. Not forgetting the entire graduate assistant that shared their precious time with me to teach me anything that may directly and indirectly help me in completing this report. I also would like to thank my friends for their support and help throughout the project duration.

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CHAPTER 1

INTRODUCTION

1.1 Background of Study

1.1.1 Enhanced Oil Recovery

There are three stages of oil recovery, primary recovery, secondary recovery and tertiary recovery, which are also widely known as Enhanced Oil Recovery (EOR). The primary recovery is when the oil flow naturally from the wellbore up to the surface due to the natural difference in term of pressure between the two points. In this stage, the oil can be recovered is about ten percents (10%) of the total oil in place. The secondary recovery takes place when the oil will no longer be able to be produced naturally. In this case, pressurized gas or water will be injected into the reservoir by injection wells. The reason for this process is to create a high pressured reservoir condition to drive the residual oil to the surface. This stage of recovery improves the recovery factor to up to forty percents (40%).

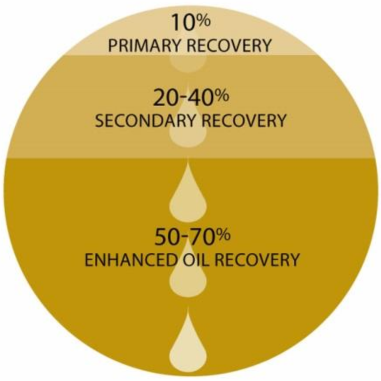


Figure 1: Oil Recovery Stages [13]

The EOR stage takes place when the secondary recovery is no longer economical and effective. EOR mainly is the injection of different materials in order to improve the flow between oil, gas and rock, thus recovering the remaining crude oil. By applying the EOR processes, the recovery factor can be further increased to approximately fifty percents (50%) to seventy percents (70%).

Major type of EOR applications are miscible displacement (injection of hydrocarbon gas or carbon dioxide), chemical flooding (alkaline, surfactant, foam, or polymer) and thermal recovery (steam flooding or in-situ combustion). In this report, we will be focusing on one of the EOR method, which is the foam injection.

1.1.2 Foam Injection

Gas injection is widely used in recovering hydrocarbon for several reasons. Availability and low cost to name some. However, due to the low density and high mobility of injected gas compared to the oil in the reservoir, the sweep efficiency is low and inefficient. The properties of the injected gas will lead to unwanted phenomena occurrence such as viscous fingering of the gas through the oil column, gravity override where the injected moved to the upper part of the oil column due to density and gravitational effect, and the gas flow on the same, least resistance path. This effect can somehow be minimize or even nullified by introducing foam into the injection system.

There are generally two uses of foam in the oil recovery process. Firstly, the foam will help in improving the sweep efficiency by reducing the gas mobility. Foam has been used to control the gas mobility in the reservoir and eventually improving the sweep efficiency by increasing the effective viscosity of the gas and decreasing the permeability of the gas. Once the foam has formed in the reservoir, its overall mobility is very low. The second function of the foam is for the gas shut off in order to reduce the gas/oil ratio (GOR) at the production wells.

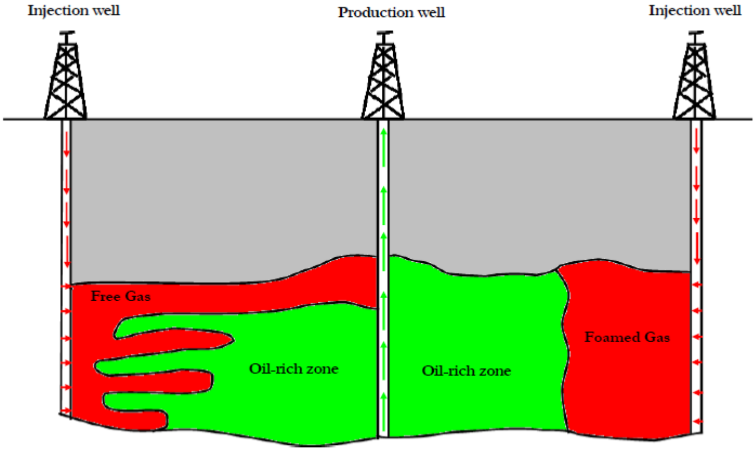


Figure 2: Gas Injection vs Foam Injection [1]

1.1.3 Injection Strategy

1.1.2.1 Surfactant concentration

Surfactant concentration is considered into the scope of the study for this simulation because for the generation of foam bubbles to take place, gas phase of high velocity needs to come in contact with continuous phase of surfactant in water. The dispersion of the gas in the liquid mixture will generate the foam bubbles. So, the surfactant concentration is an important parameter that can affect the generation intensity of the foam bubbles in the reservoir. The stability of the foam films is related to the surfactant concentration. The stability of the foam films is a function of the local capillary pressure (destabilizing pressure) and disjoining pressure (stabilizing pressure). If the disjoining pressure is higher than the local capillary pressure, the foam films will stabilize and becomes stronger.

1.1.2.2 Injection Rate

The foam injection that will be simulated in this project is of co-injection of the mixture of surfactant solution and gas. With this co-injection, the foam generation will take place nearby the injection well region. Due to this, all the oil nearby can be swept away. Co-injection is also best deployed in a reservoir with high heterogeneity degree. This is in order to guarantee that the foam bubbles slug will be formed early and go through the region intended instead of dispersing away. The injection rate here is the rate at which the gas phase will be injected into mixture of surfactant and water in the reservoir. The injection rate of the gas will affect the nature of the foam bubbles generated.

1.2 Problem Statement

i. Is foam injection really a better injection method compared to gas injection in term of oil recovery?
ii. Which concentration of foam will produce the highest recovery factor at economic cost?
iii. What is the most ideal injection rate of foam injection?

1.3 Objectives

i. To identify whether foam injection is a better injection compared to gas injection in term of oil recovery.
ii. To find out the best concentration of the foam to achieve the highest recovery factor at an economic level.
iii. To investigate the best injection rate of the foam injection.

1.4 Scope of Study

Simulation

- The model of the reservoir created will be used for simulation in determining the outcome of the foam injection in the reservoir. The model of the reservoir will need to be reliable and accurate in order to get reliable simulation results. Based on history matching, if the results of the simulations and the data available are the same or close, the model is the considered as reliable model.
- The first simulation will be on proving the effectiveness of foam injection compared to the gas. The most effective injection will be decided based on the highest total recovery of the oil.
- The simulation then will simulate the injection of foam at different foam concentration. Several value of foam concentration will be simulated to determine the most optimum foam concentration value.
- The final simulation will be on the injection rate. Different injection rate will affect the sweep pattern of the foam in the reservoir. The best injection rate will also be determined according to the total oil production from the foam injection.

CHAPTER 2

LITERATURE REVIEW

Since 1900, gas has been used as a mean to drive fluid to improve oil recovery, according to Lake (1989). This includes injectants such as steam, carbon dioxide, nitrogen, and produced field gas. This has been widely pursued due to low cost factor. These injectants, if not readily available, can be obtained at a negligible cost compared to any other secondary or tertiary recovery methods. However, there are some limiting factors for the gas application in recovering oil. Shan and Rossen (2004) indicate that these factors are low gas density, high gas mobility and reservoir heterogeneity. This will eventually lead to one major problem, poor sweep efficiency of the oil.

The introduction of foam into the injection process proved to be successful in rectifying the poor sweeping efficiency of gas. According to Andrianov et al. (2012), the foam may affect the oil recovery in different ways compared to gas injection or water-alternating-gas (WAG) injection. In foam injection, the oil displacement process is more stable as the viscosity of the displacing liquid will increase due to the presence of the foam. The foam also will help the recovery by blocking the high permeability zone, diverting the displacing the fluid into the previously unswept zone. Furthermore, due to the presence of surfactant in the foam injection, the interfacial tension between the residual oil and displacing fluid will be reduced, resulting in higher recovery of the oil. Alex et al. (1998) state that foam injection is proven to have increased the oil production by 1.5 to 5 times as well as lowering the water cut by 20%.

Foam is a liquid mixture gas and liquid where the liquid phase containing surfactant. Dispersion of the gas in the continuous liquid phase will generate the foam. Falls et al. (1988) and Hirasaki (1989) agree that the continuous liquid phase will be wetting the rock while a portion or all of the gas will be made discontinuous by lamellae, which are thin liquid films.

The liquid films connecting the foam on the grains are the one responsible for the continuous structure of the liquid phase. Meanwhile, the discontinuous gas phase is organized in gas bubbles (Exerowa and Kruglyakov, 1998). This is illustrated by the figure below.

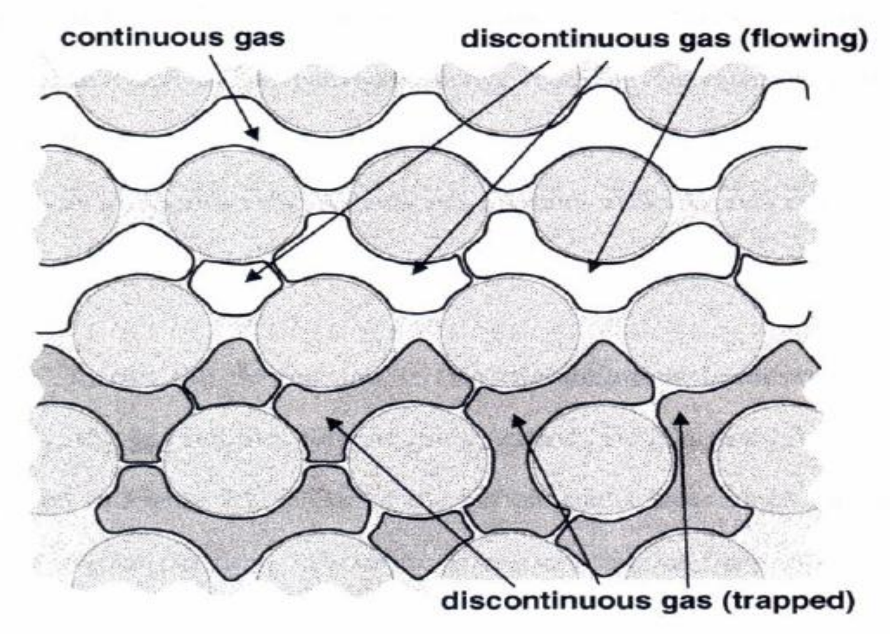


Figure 2: Gas behaviour in foam presence [12]

Foam has improved the sweep efficiency by reducing the mobility of gas in the reservoir. The concept behind the function of the foam is entrapment of gas bubbles. According to Falls et al. (1989), some of the gas bubbles will be trapped by the foam, which will reduce the effective gas permeability. Rossen (1996) find that when the foam films are created in the reservoir porous media, the flow of the gas is hindered significantly. When the natural flow of the gas is restricted, the gas will flow around the trapped gas. This will allow the gas to contact the oil that would not been reached otherwise. Kovschek and Radke (1994) add that in the presence of foam, the gas mobility is largely influenced by foam texture or bubble size. Smaller bubbles reduce greater gas mobility compared to larger bubbles. This is because smaller foam bubbles are more stable and stronger than larger sized foam bubbles.

Foam concentration in the reservoir is directly affected by the surfactant concentration. Friedmann et al (1991) have shown that there is certain concentration of surfactant needed in order for the generation of foam to take place. The concentration is called the minimum surfactant concentration. Aronson et al (1994) supported this by stating that the stabilizing pressure will increase as the surfactant concentration is increased pass the minimum concentration mark. Apaydin and Kovscek (2000) states that foam coalescence forces are inversely proportional to the concentration of surfactant. Therefore, as the surfactant concentration decreases, the foam weakens and the displacement efficiency suffers. Friedman and Jensen (1986) find that by increasing the surfactant concentration, the size of the foam bubble in the porous media will be reduced.

The injection rate also affects the foam dynamics strongly. Friedman and Jensen (1986) also suggest that at high flow rate, the foam generated will be smaller and possess more uniform bubble sizes, thus making the foam more stable compared to the foam generated at low flow rate. According to Osterloh and Jante (1992) there are two flow regimes exist for foam flow in porous media, the low gas fractional flow regime and high gas fractional flow regime. In the first regime, the foam apparent viscosity is deemed to increase with the gas rate (independent of liquid rate) while the second regime apparent foam viscosity increases with the liquid rate.

CHAPTER 3

METHODOLOGY

3.1 Simulation Model Details

The simulation of the foam injection on the reservoir model is carried out using ECLIPSE simulation software. The field selected to be the model of the simulation are real field in Malaysia which will be referred as field B in this report. The simulation will be conducted on 15x15x10 block model of reservoir. The length and width of each block are both set to 100ft. The thickness of each block is set to 20ft. this will total up the reservoir model to be 1500ft in length and width and 200ft deep in thickness, taking the bulk and pore volume to be 450,000,000 ft3 and 135,000,000 ft3 respectively. The depth of the top layer is 4200ft into the ground. The fluid phases present in the model are oil and water initially. After some time of production, as the reservoir model's pressure will drop, the gas which is initially soluble in the oil will be liberated. Therefore, throughout the simulation, the phases present would be oil, gas water and foam. The gas-oil contact and oil-water contact are 4173ft and 4455ft respectively. The connate water saturation is 12%.

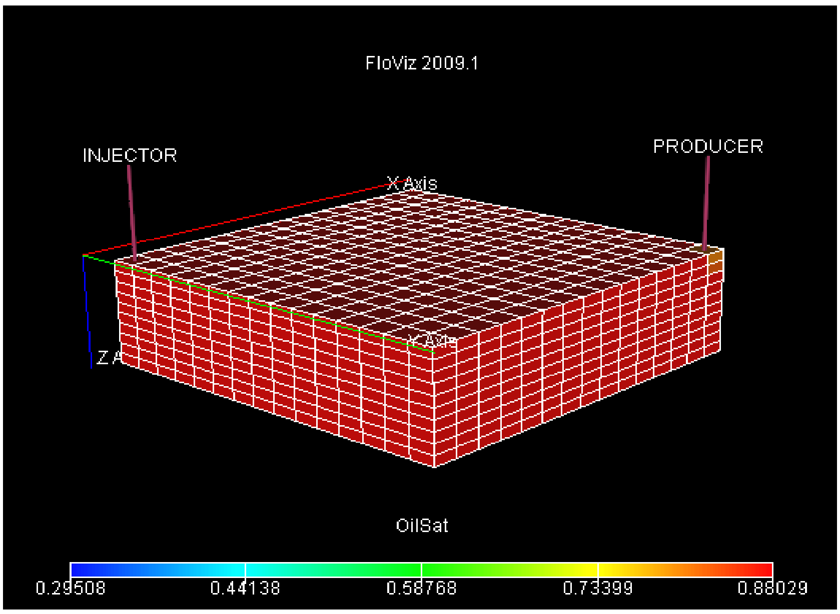


Figure 3: Simulation Model

In order to not overcomplicate the simulation, some of the reservoir model's parameters will be assumed homogeneous and isotropic. The porosity of the model is set to be 30% while. The absolute permeability of each block is set to 50 md.

The PVT data of the fluids are taken from the Field B data available. The densities of the fluids were also extracted from the Field B fluid properties along with other fluid properties such as the solution gas-oil ratio, formation volume factor, and viscosity. The bubble point pressure of the oil is at 1332 psig and the initial pressure of the reservoir at a datum depth 4265ft is 1332 psig. The reservoir temperature at the datum is determined to be 215°F.

For the foam properties such as foam decay rate, foam mobility reduction factor and halflife values together with fluids adsorption rate of rock, they are imported from ECLIPSE simulator manual. This is because as they are not in the scope of the study, their value can be simply taken from past simulation as long they are within the range of the possible values.

In order to properly see the pattern of the displacement of the foam bubbles, the production and injection wells are placed at the corner of the reservoir model as can be seen from the figure above. By placing them at the corner, the distance between them will be the farthest therefore the displacement efficiency of the foam injection can be evaluated properly. The wellbore diameter is set to be 0.5ft in length, being able to accommodate the 2 7/8" tubing in between.

3.2 Simulation Procedures

Before any injection is simulated, the reservoir model is produced naturally for a duration of time first. This is to avoid miscalculation of the efficiency of the injections simulated due to the primary recovery mechanism. The injection is will take place before the reservoir pressure decline below the bubble point pressure. This is to prevent the gas dissolved in the oil to be liberated and dominating the production instead of oil.

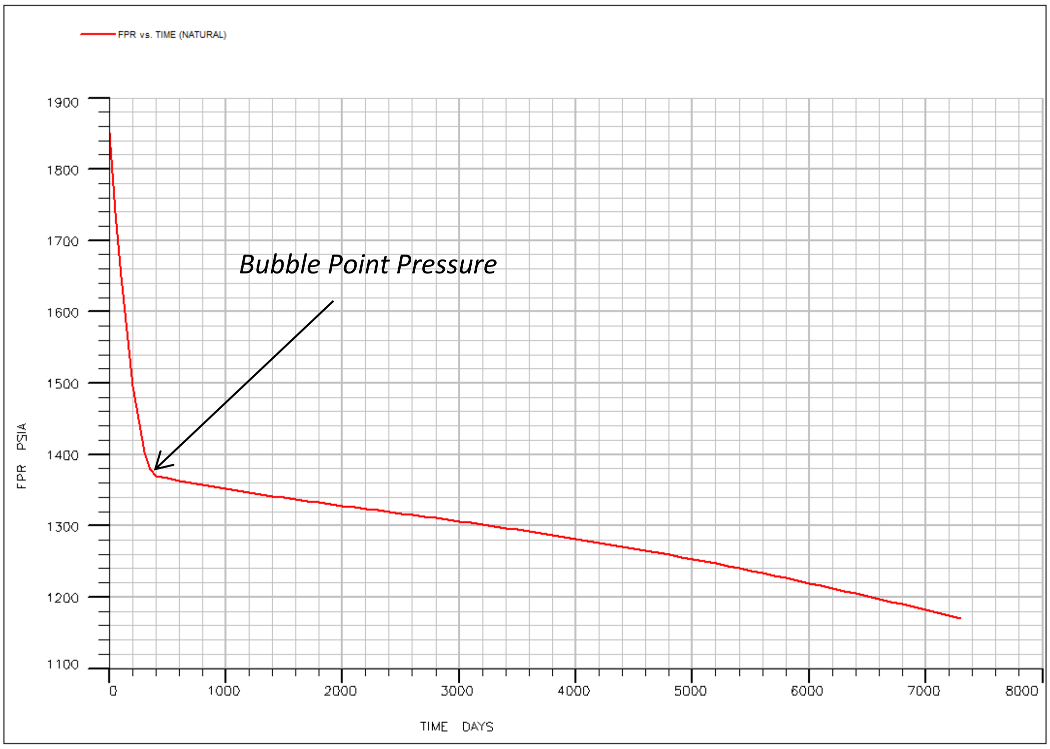


Figure 4: Natural Production Pressure Profile

From the figure above, the exact time for the injection to be initiated is before the bubble point is reached, which is when pressure starts to decline at slower rate. The slower decline rate indicates that gas has been liberated and occupying spaces and maintaining the pressure in the reservoir. Therefore, the time for the injection is set to after 1 year of production (365 days).

The injections then will be simulated as follow:

I. Type of Injection

a. Gas Injection
b. Foam Injection

Table 1: Type of Injection Simulation

No	Injection Type	Surfactant Concentration (lb/stb)	Injection Rate (Mscf/day)
1	**Gas Injection**	-	800
2	**Foam Injection**	5.0	800

II. Injection Surfactant Concentration

a. 1.0 lb/stb
b. 5.0 lb/stb
c. 10.0 lb/stb
d. 15.0 lb/stb

Table 2: Surfactant Concentration Simulation

No	Injection Type	Surfactant Concentration (lb/stb)	Injection Rate (Mscf/day)
1	Foam Injection	**1.0**	800
2	Foam Injection	**2.5**	800
3	Foam Injection	**5.0**	800
4	Foam Injection	**10.0**	800
5	Foam Injection	**15.0**	800

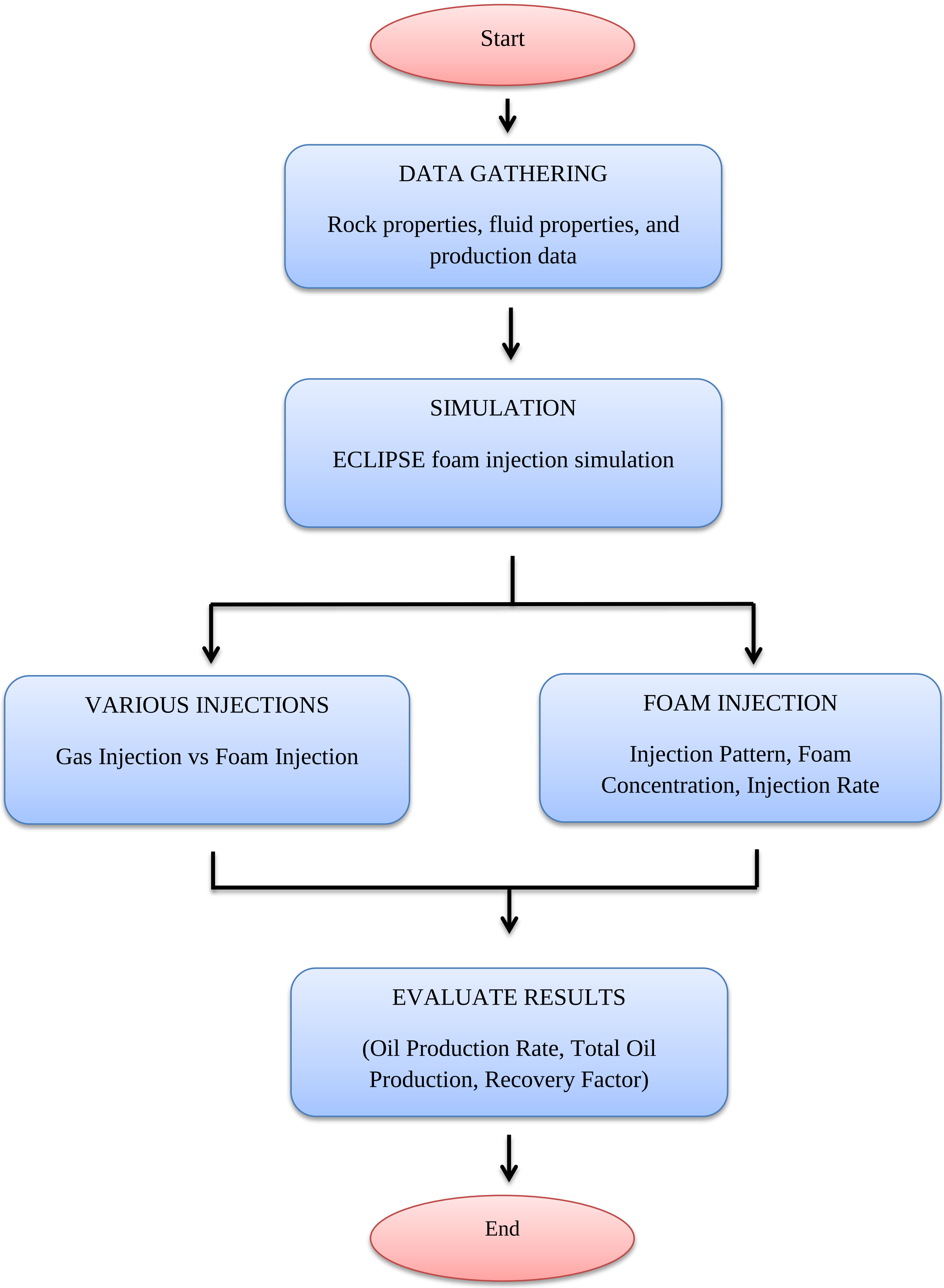
III. Foam Injection Rate

a. 500 Mscf/day
b. 600 Mscf/day
c. 700 Mscf/day
d. 800 Mscf/day
e. 900 Mscf/day
f. 1000 Mscf/day

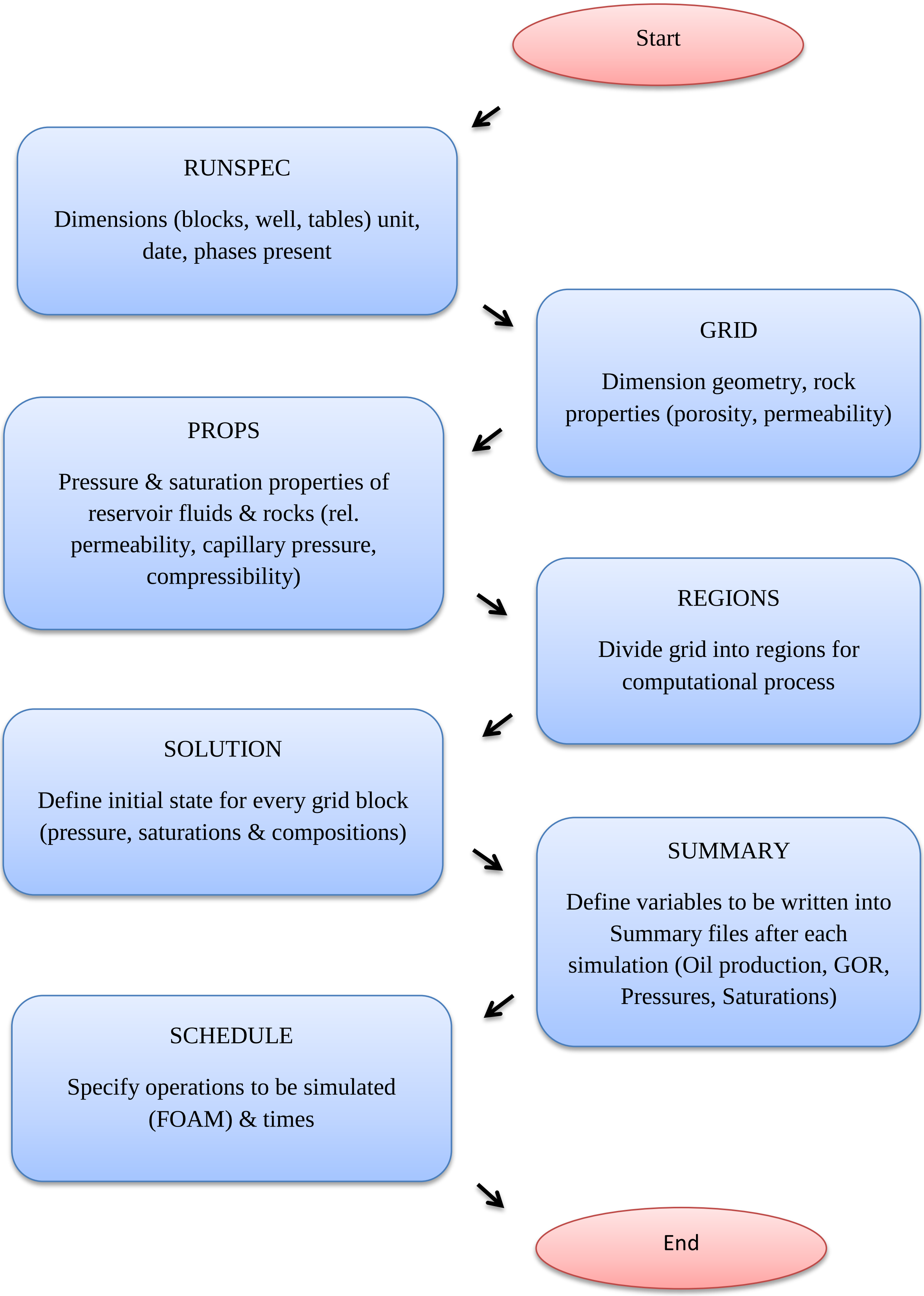
Table 3: Injection Rate Simulation

No	Injection Type	Surfactant Concentration (lb/stb)	Injection Rate (Mscf/day)
1	Foam Injection	5.0	**500**
2	Foam Injection	5.0	**600**
3	Foam Injection	5.0	**700**
4	Foam Injection	5.0	**800**
5	Foam Injection	5.0	**900**
6	Foam Injection	5.0	**1000**

3.3 Project Flowchart



3.4 Eclipse Flowchart



3.5 Gantt Chart

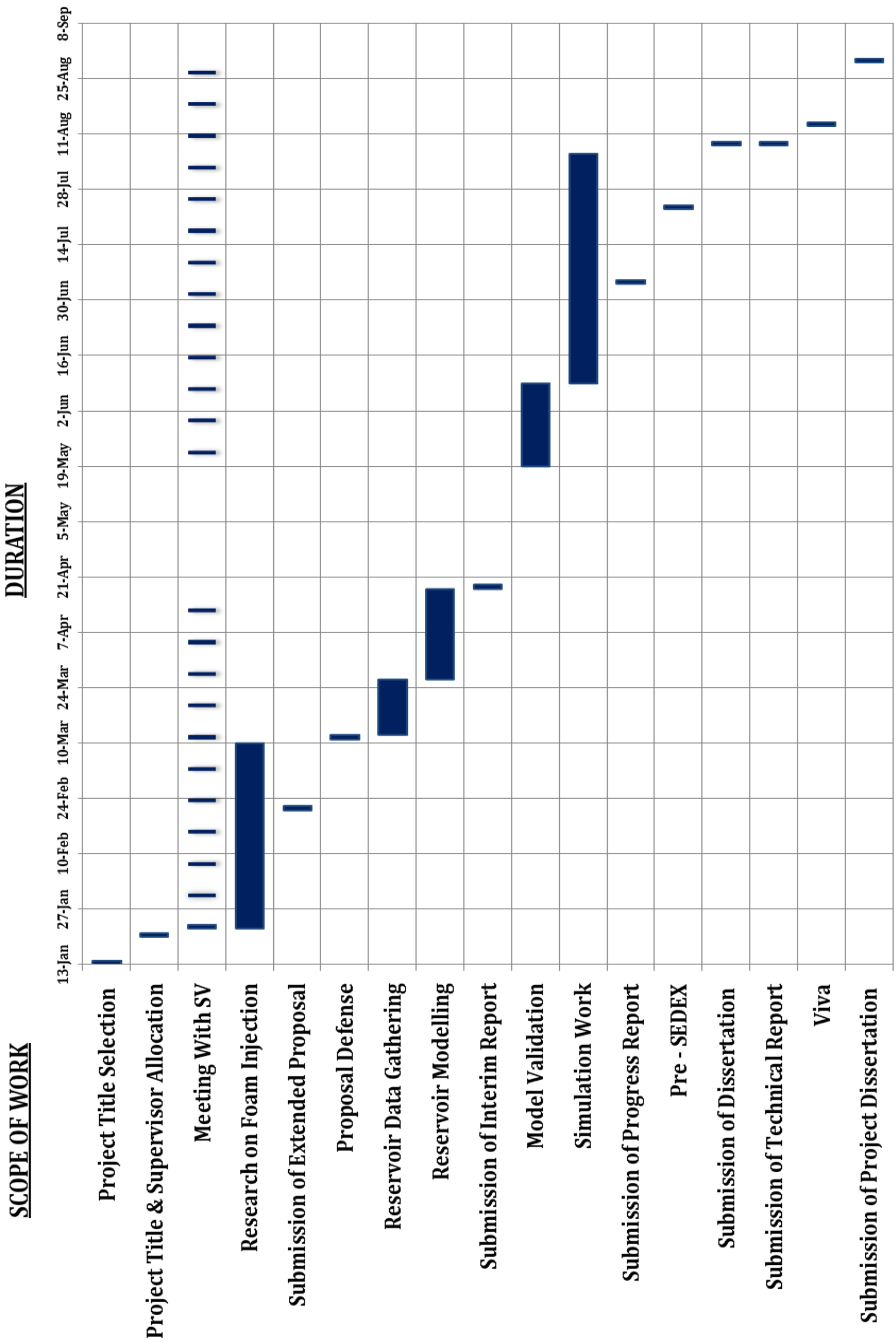


Figure 5: Project Gantt chart

CHAPTER 4

RESULTS AND DISCUSSIONS

Based on the simulations that have been conducted as stated in methodology section, the results obtained are as follow:

4.1 Type of Injection

a. Gas Injection

b. Foam Injection

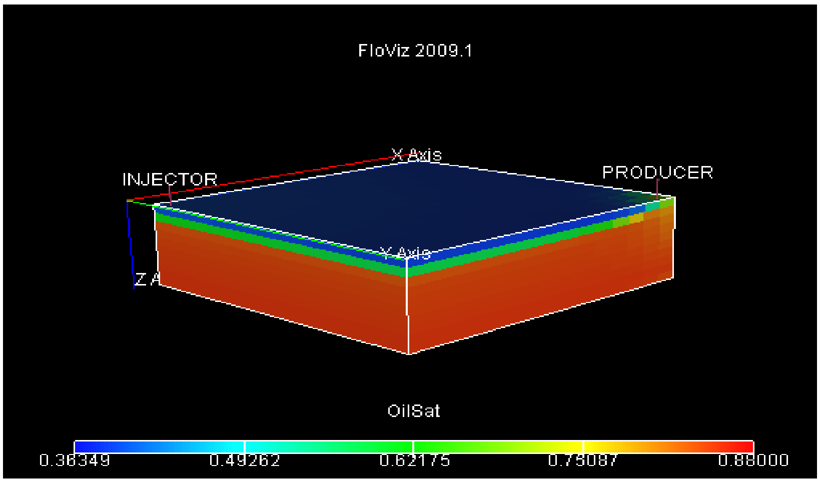


Figure 6: Natural Production (no injection)

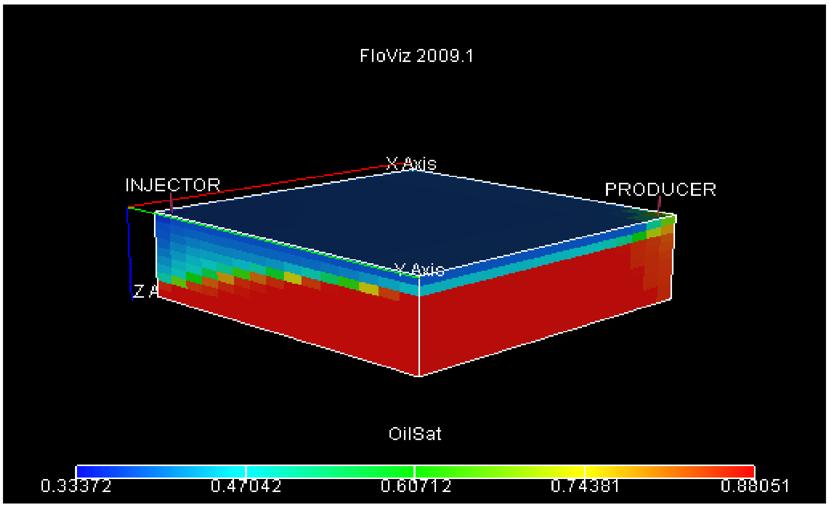


Figure 7: Gas Injection

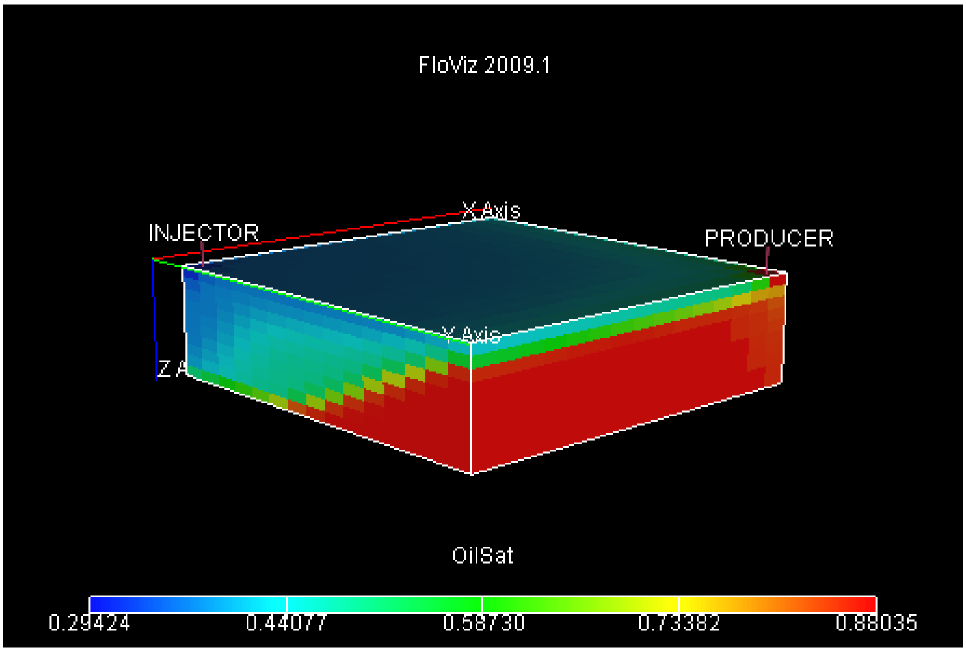


Figure 8: Foam Injection

The figure 8, 9 and 10 above are the simulated reservoir model for natural production (no injection operation), gas injection, and foam injection after 12 years, respectively. The movement of the injected fluid are form the injector (left corner) to the producer (right corner). For this part, we are going to compare the sweep efficiency of the gas and foam injection. As can be seen from the figures above, the sweep efficiency of the foam injection in figure 10 is the better of the two. For the gas injection in figure 9, gravity segregation has become more significant and dominant, resulting in gravity override. The same can be said with foam injection, although the degree of the gravity override is not as severe as in gas injection. This is due to the presence of the foam bubbles in the reservoir, reducing the mobility if the gas bubbles thus resulting in a much improved sweep pattern and efficiency.

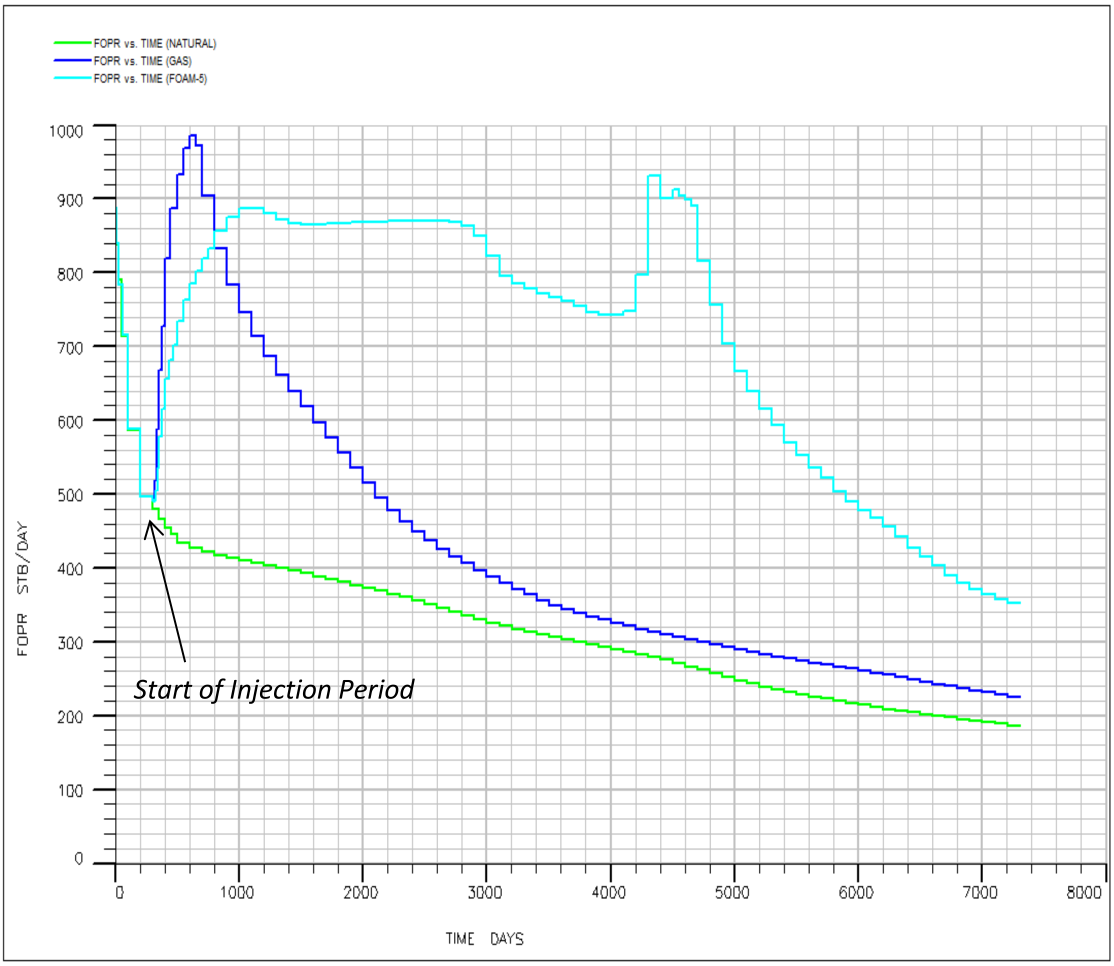


Figure 9: Graph of Oil Production Rate vs Time

Referring to the figure above, natural production, gas injection and foam injection curves are represent by green, blue and indigo line respectively. After the injection period, the oil rate from gas injection increase sharply, only to drop severely after a short while. In the case of foam injection, it can be considered more stable and producing at a higher rate for a large portion of time when compared to gas injection. The recovery rate over time figure above indicates that the foam injection is the injection method that can achieve the highest production rate after the primary recovery stages, upstaging gas injection.

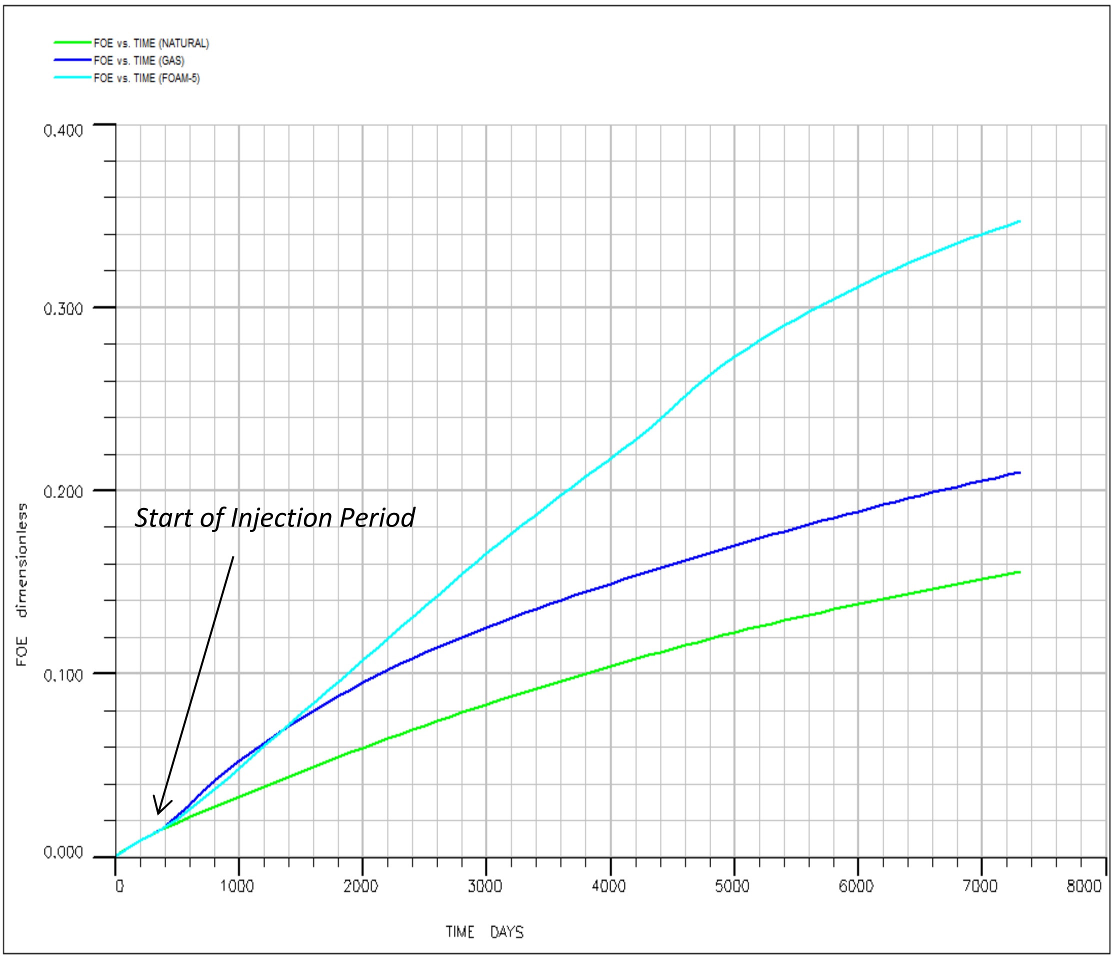


Figure 10: Graph of Oil Recovery Factor vs Time

From figure 12, we can see the recovery factor for each of the case. After 20 years, the recovery factors for natural production, gas injection and foam injection are 15.7%, 21.0% and 34.6% respectively. Therefore, foam injection will be able to record additional 18.9% of oil recovery only by the addition of surfactant into the gas injection operation. By looking at the trend, it is highly probable that the recovery factor will keep on increasing over time. Therefore, it is proven that the foam injection will be able to record higher production of oil compared to gas injection, by mitigating the mobility of the gas in the reservoir.

4.2 Surfactant Concentration

a. 1.0 lb/stb

b. 2.5 lb/stb

c. 5.0 lb/stb

d. 10.0 lb/stb

e. 15.0 lb/stb

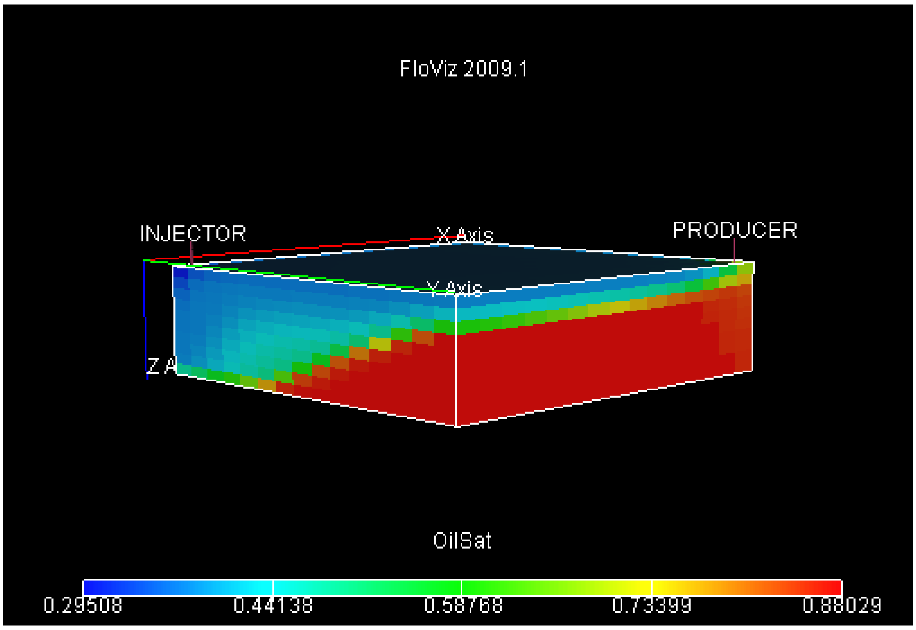


Figure 11: 1.0 lb/stb concentration

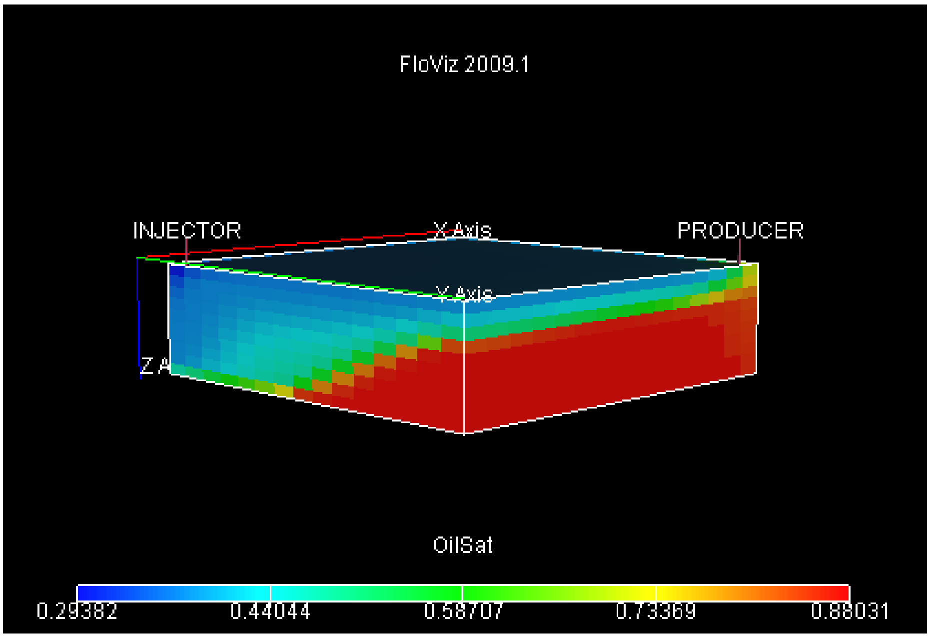


Figure 12: 2.5 lb/stb concentration

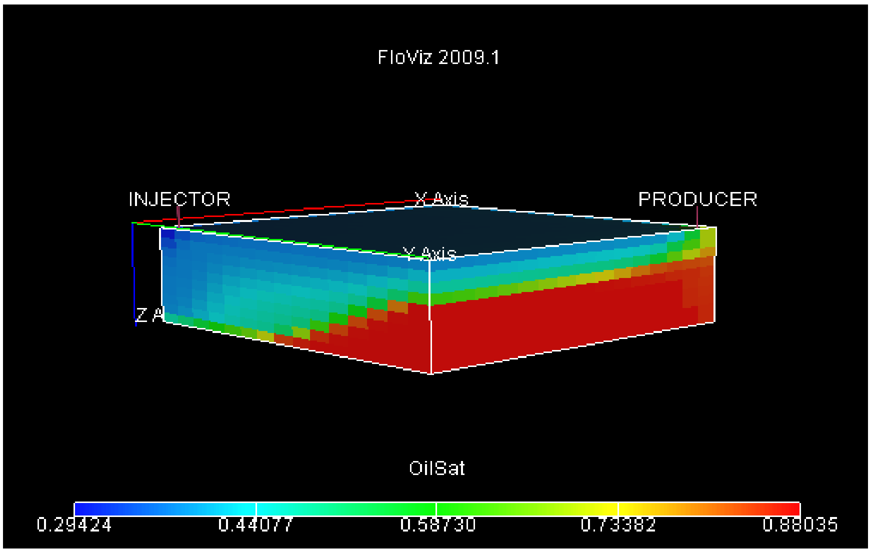


Figure 13: 5.0 lb/stb concentration

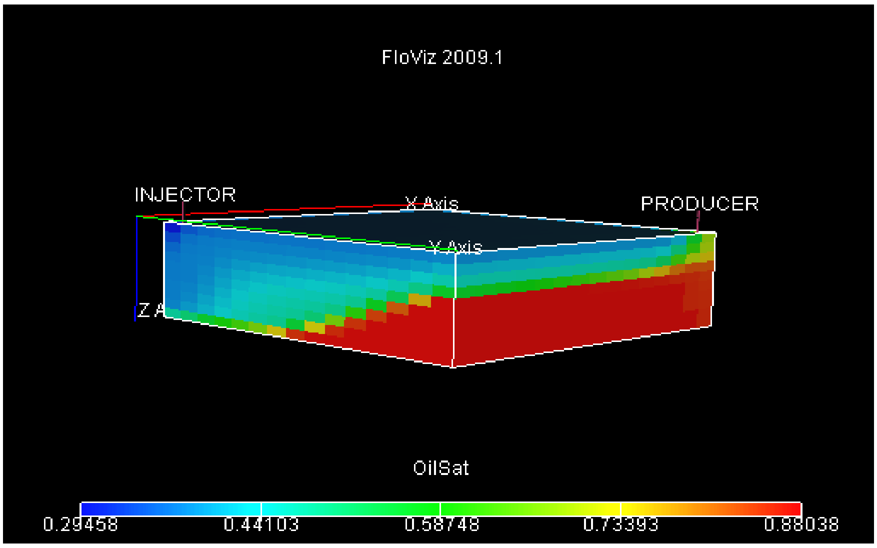


Figure 14: 10.0 lb/stb concentration

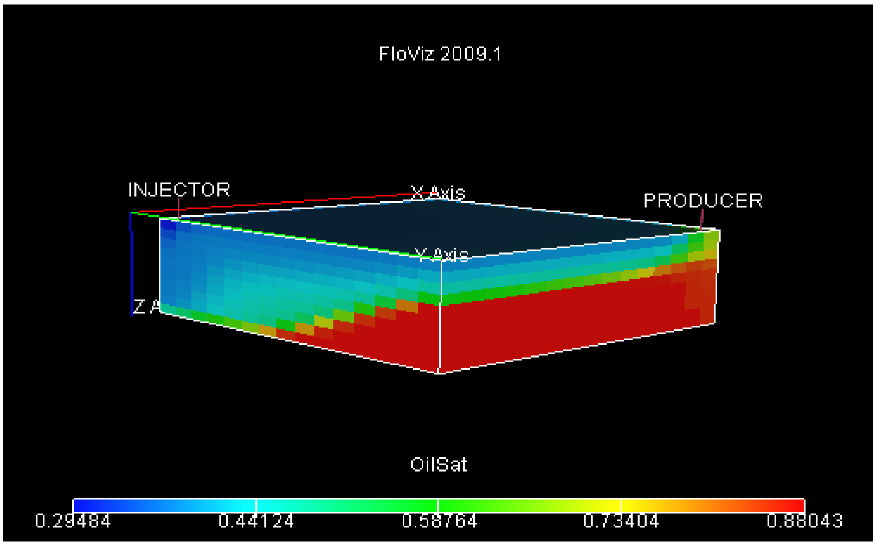


Figure 15: 15.0 lb/stb concentration

The figures above are what the sweep pattern looks like after 18 years of foam injection. Based on the figures above, there is not much difference in the sweep pattern between the 5.0 lb/stb, 10.0 lb/stb and 15.0 lb/stb. This may indicate that 5.0 lb/stb is the optimum concentration for the foam injection. For the 1.0 lb/stb and 2.5 lb/stb concentrations however, the foam injection may not be as effective as the 5.0 lb/stb concentration.

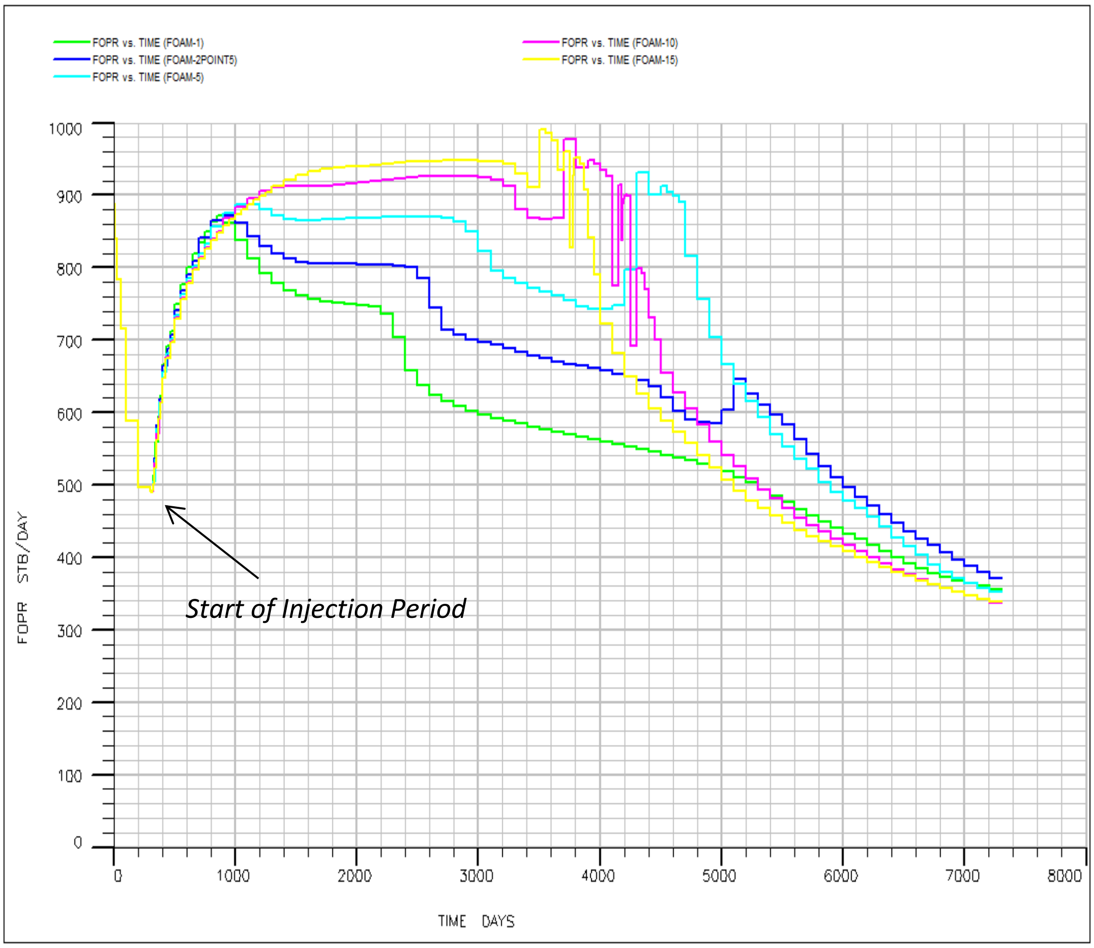


Figure 16: Graph of Oil Production Rate vs Time

From the graph above, it can be seen that the higher the concentration, the higher the resultant oil production rate. The 15.0 lb/stb concentration records the highest oil production rate, almost reaching 1000 stb/day mark. However, the higher the surfactant concentration, the more intense the oil production rate after some time as can be seen from the 5.0 lb/stb, 10.0 lb/stb and 15.0 lb/stb curves.

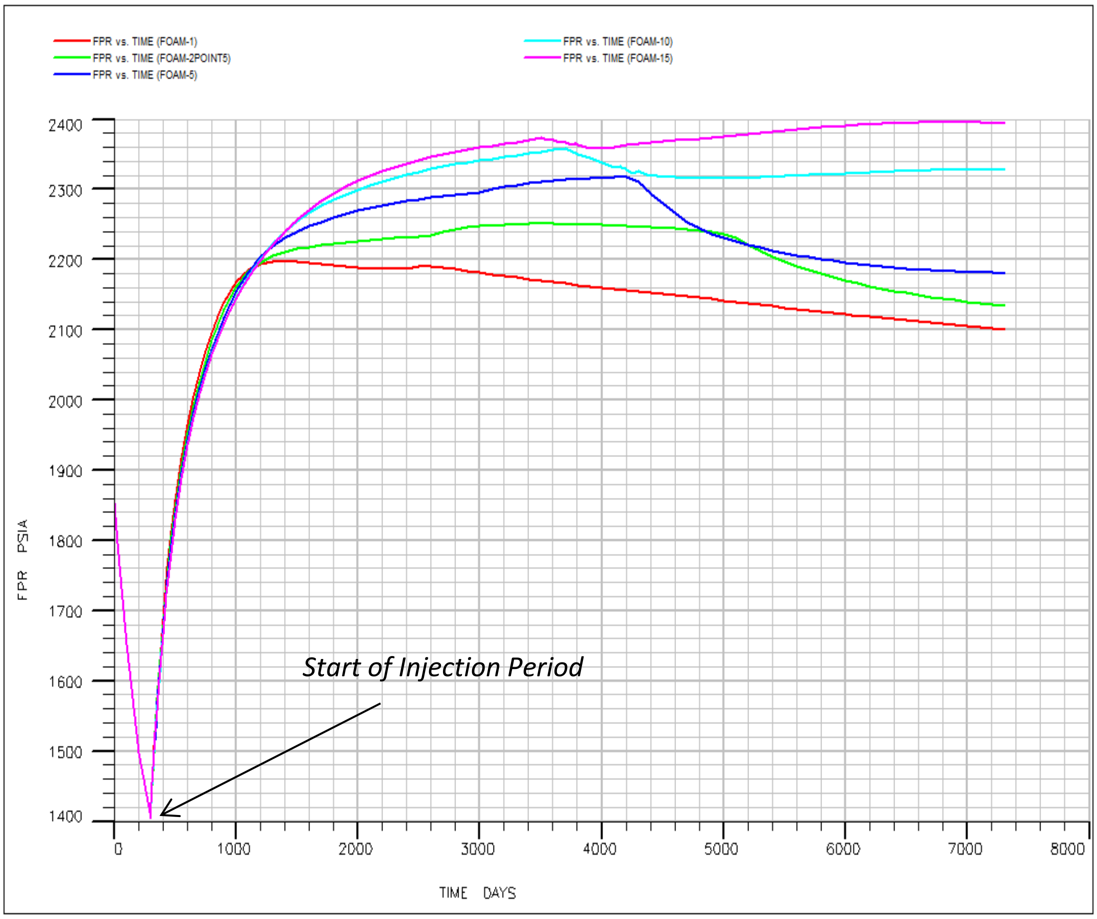


Figure 17: Graph of Pressure vs Time

From figure 18, the pressure of the reservoir at the respective surfactant concentration can be determined. The pressure profile gives the ability to screen the surfactant concentration. As the initial pressure of the reservoir is 1869 Psia, the resultant pressure from the foam injection that record higher pressure than the initial reservoir pressure is deemed to not be suitable and feasible. This is because to avoid reservoir and formation fracture due to high pressure region created during the injection. However, if we are to allow 500 Psia additional pressures that can be handled by the reservoir, we can consider a lot more option in the foam injection strategy. Therefore, for this simulation, we are going to assumed that the reservoir can handle the 500 additional pressures on top of the initial reservoir pressure. With the assumption, we will exclude any injection that exceeds 2369 Psia resultant pressure. So, based figure 18, we will exclude 15.0 surfactant concentrations from the possible selection of the best surfactant concentration.

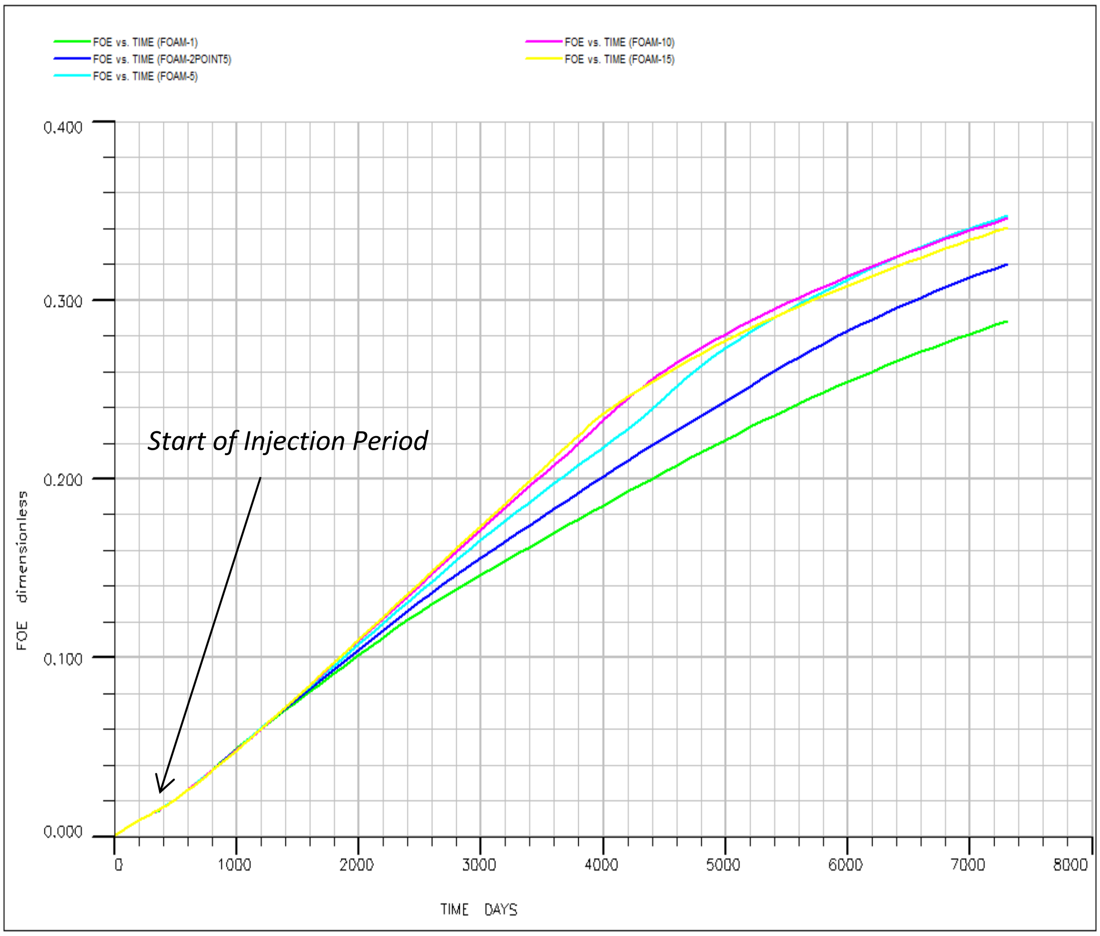


Figure 18: Graph of Oil Recovery Factor vs Time

As 15.0 lb/stb concentration is no longer an option, the best surfactant can only be either 5.0 lb/stb or 10.0 lb/stb. By referring to figure 20, we can see that there is little to no difference between the recovery factor value of the 5.0 and 10.0 lb/stb. This suggests that in order to carry out an optimum and economic injection operation, 5.0 lb/stb surfactant concentration should be carried out, because the amount of surfactant needed for 5.0 lb/stb operation is half of the amount for 10.0 lb/stb operation.

4.3 Foam Injection Rate

a. 500 Mscf/day
b. 600 Mscf/day
c. 700 Mscf/day
d. 800 Mscf/day
e. 900 Mscf/day
f. 1000 Mscf/day

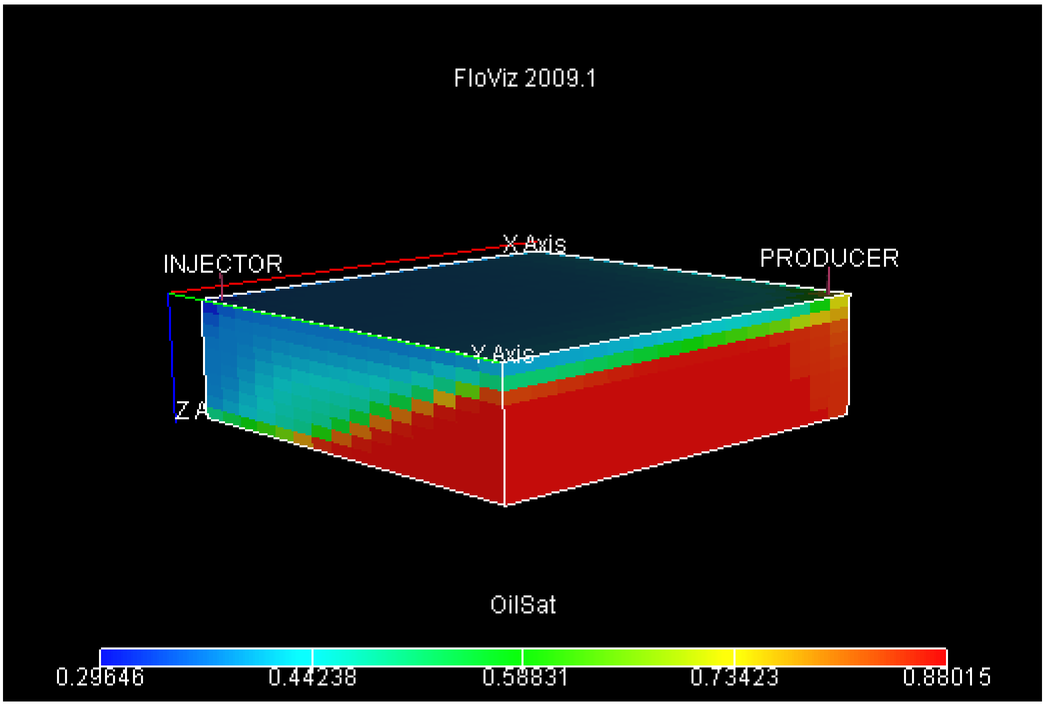


Figure 19: 500 Mscf/day

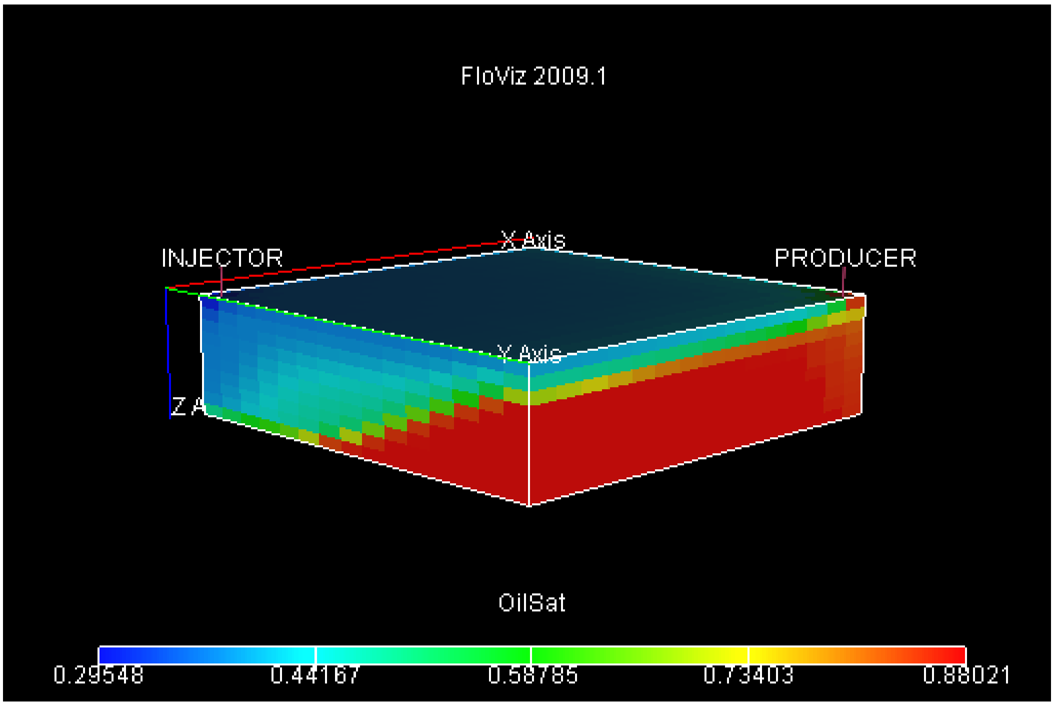


Figure 20: 600 Mscf/day

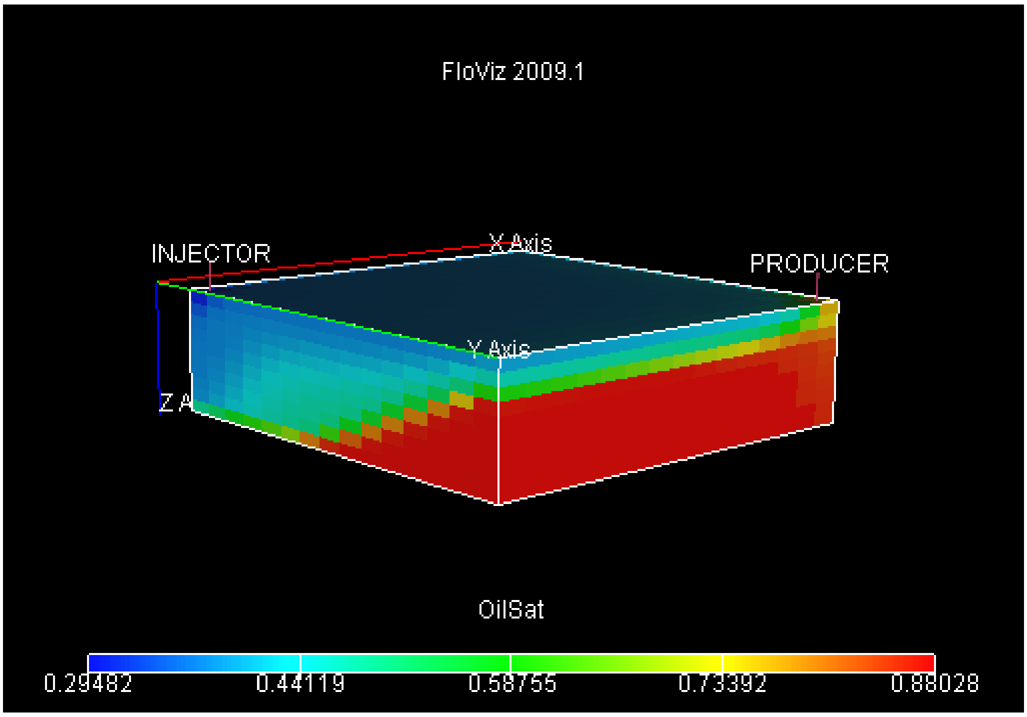


Figure 21: 700 Mscf/day

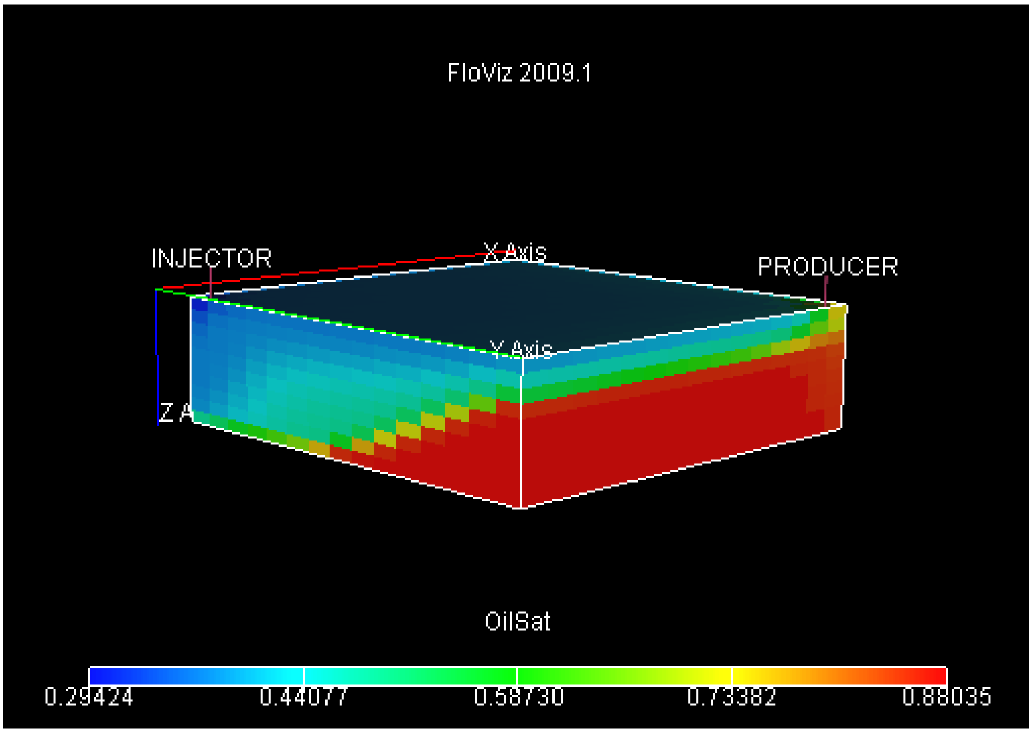


Figure 22: 800 Mscf/day

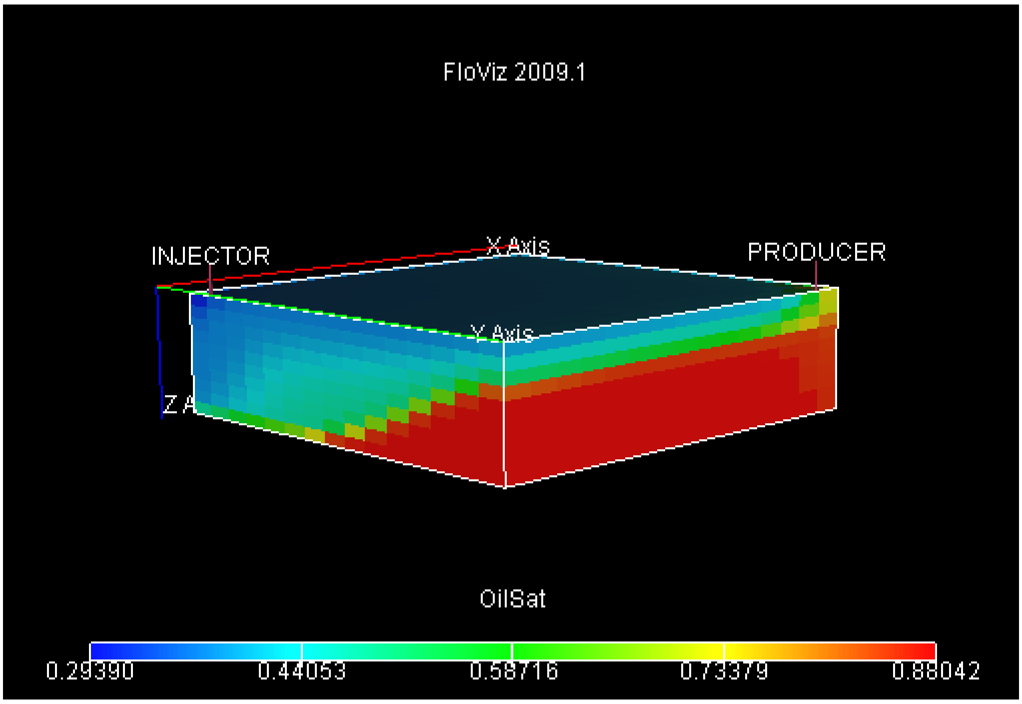


Figure 23: 900 Mscf/day

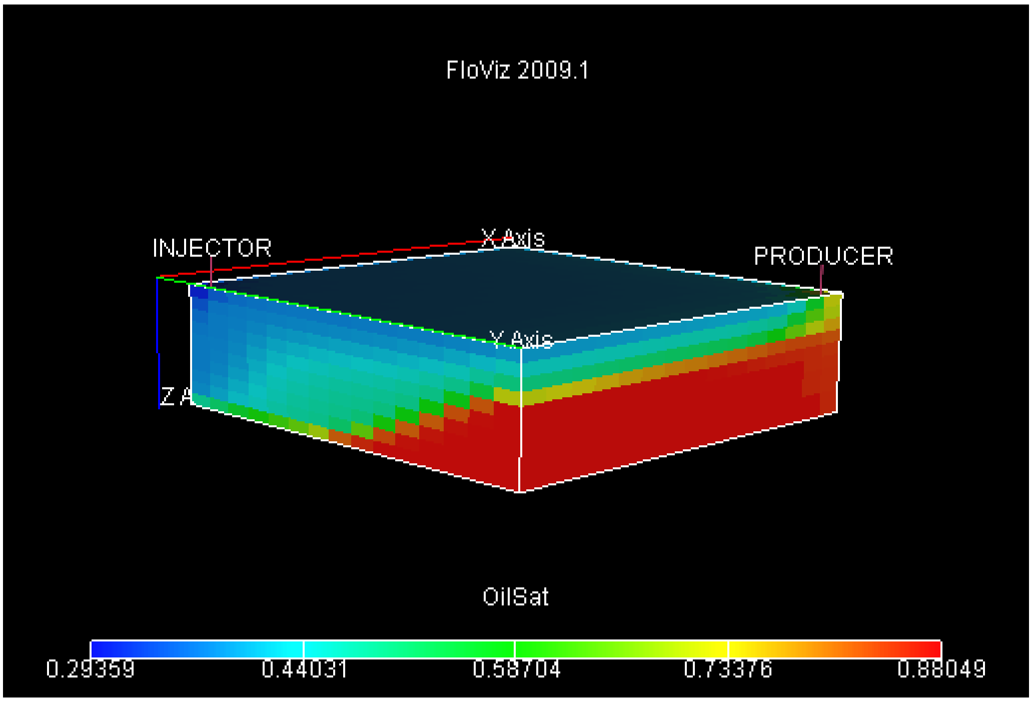


Figure 24: 1000 Mscf/day

The figures above are the sweep pattern of the foam injection at different rate after 15 years of injection. As can be seen, the higher the foam injection rate, the better the sweep pattern and efficiency. This will eventually results in higher recovery factor.

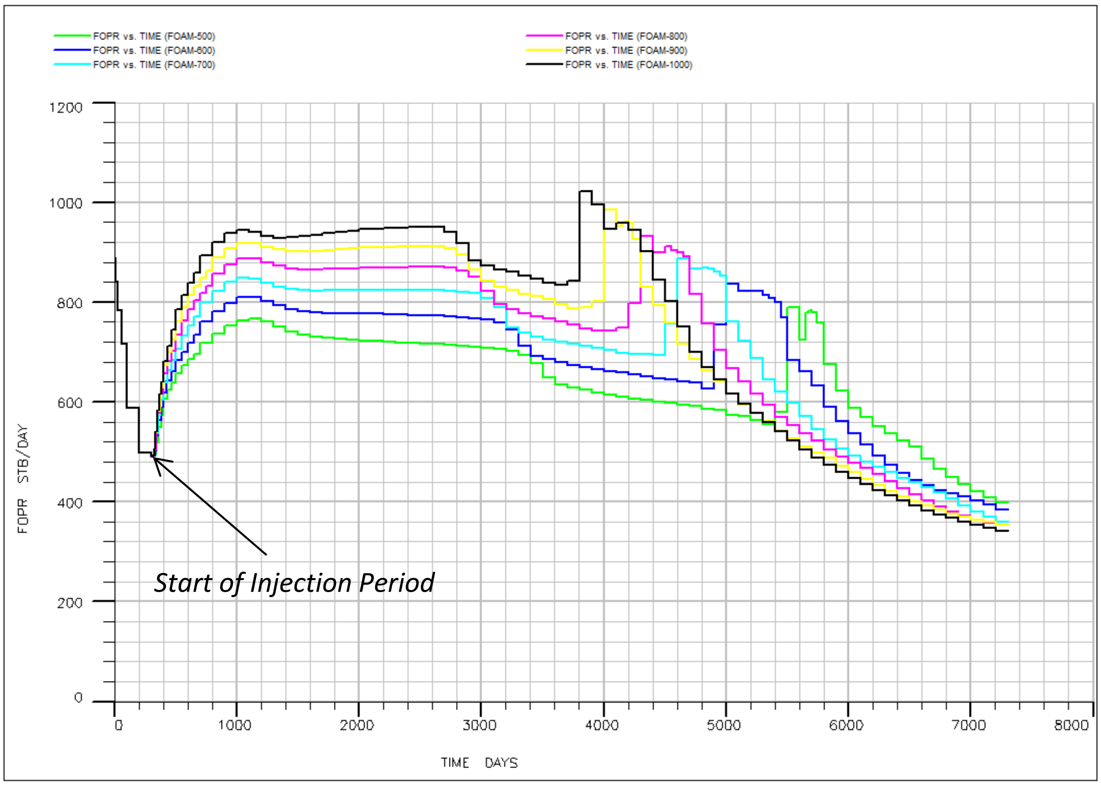


Figure 25: Graph of Oil Production Rate vs Time

The injection rate of 500 Mscf/day, 600 Mscf/day, 700 Mscf/day, 800 Mscf/day, 900 Mscf/day and 1,000 Mscf/day are represented by green, blue, indigo, pink, yellow and black respectively. The oil production rate increases with the injection rate.

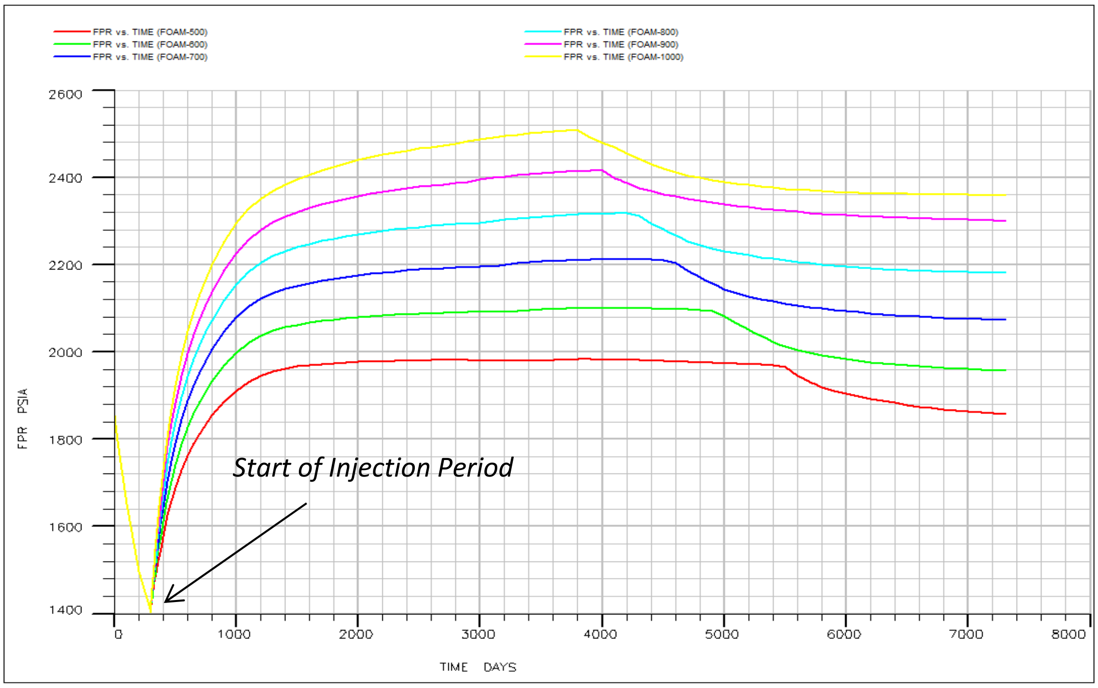


Figure 26: Graph of Pressure vs Time

From figure 27, again the pressure profile will be used for screening of the foam injection strategy. By allowing 500 permissible additional pressures that can be sustained by the reservoir on top of the initial reservoir pressure (1869 Psia), 900 Mscf/day and 1000 Mscf/day can be excluded from the consideration.

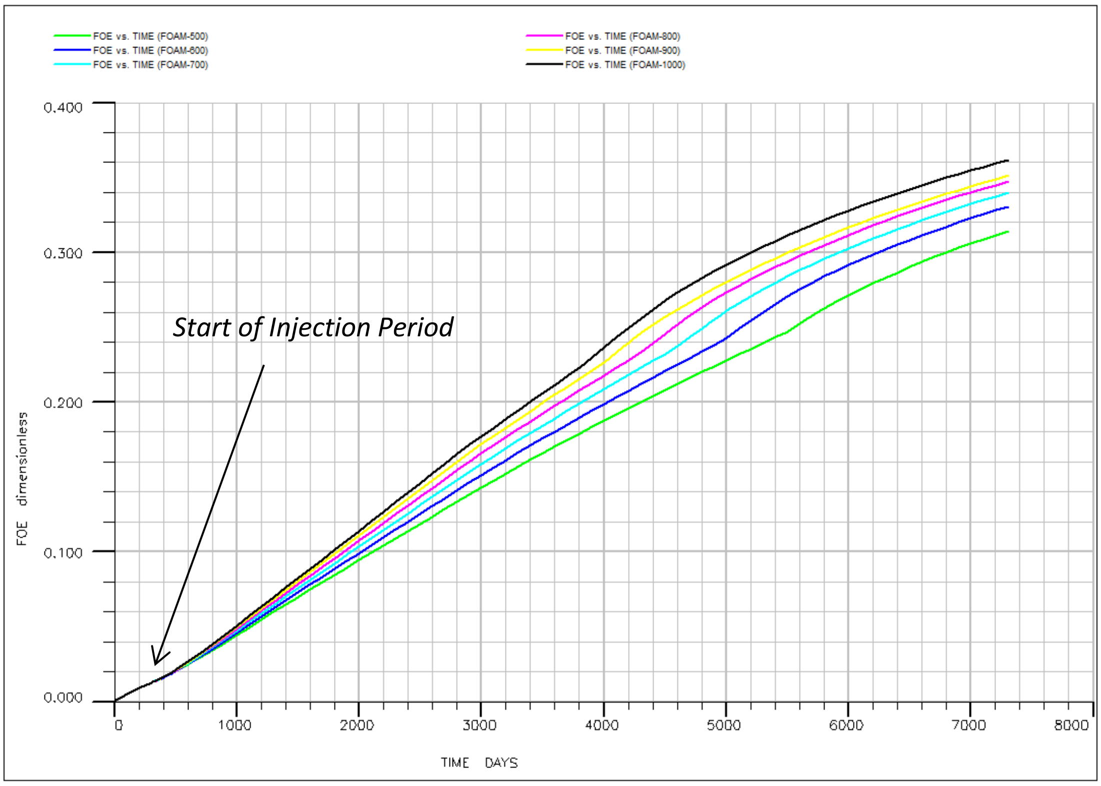


Figure 27: Graph of Oil Recovery Factor vs Time

With only 500 Mscf/day, 600 Mscf/day, 700 Mscf/day and 800 Mscf/day up foe consideration, we will look at the recovery factor to make the final decision. They are illustrated by the green, blue, indigo and pink line respectively in figure 28 above. As shown by the graph above, the oil recovery from injecting the foam at 800 Mscf/day are the highest, followed by the injection at 700 Mscf/day, 600 Mscf/day and finally 500 Mscf/day. As 800 Mscf/day injection are not ruled out as unrealistic, it will be considered as the best injection rate for the foam injection operation.

CHAPTER 5

CONCLUSION & RECOMMENDATION

5.1 Conclusion

Based on the objective stated at the beginning of the report, the conclusions are as follow:

i. In term of oil recovery, foam injection is proven to be better than gas injection.
ii. The concentration of the surfactant for the foam injection that will produce the highest recovery factor at an economic level is 5.0 lb/stb.
iii. The most ideal and realistic injection for the foam injection is found out to be 800 Mscf/day.

Therefore, by considering all the parameters tested in the simulation, the best foam injection strategy would be injecting the foam at 5.0 lb/stb surfactant concentration at 800 Mscf/day.

5.2 Recommendations

From the simulation carried out, it can be seen that the foam injection have the potential to be among the best EOR methods to be carried out. The only setback is the elimination of the foam bubbles over time. The decay rate of the foam bubble are the function of foam bubbles half-life and adsorption by the rock. From the parameters mention, it can be said that the effectiveness of the foam injection are a function of time and length of the reservoir. Therefore, in order to improve the effectiveness of the foam injection, we can either apply the foam injection for smaller reservoir or by reducing the well spacing (increase the amount of injectors and producers well).

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APPENDIX

ECLIPSE DATA FILE

RUNSPEC

```
RUNSPEC
TITLE
    FOAM Injection model (5)

DIMENS
   15   15    10  /

OIL

WATER

GAS

DISGAS

UNIFOUT

FOAM

FIELD

EQLDIMS
    1   100   10    1     1 /

TABDIMS
    2     1   16   12     2   12    1     1 /

REGDIMS
    2     1     0     0   /

WELLDIMS
    2     100     1     2 /

NUPCOL
    4 /

START
  1 'JAN' 1991   /

NSTACK
   25 /
```

GRID

```
GRID     ==================================================================
-------- IN THIS SECTION , THE GEOMETRY OF THE  SIMULATION GRID AND THE
-------- ROCK PERMEABILITIES AND POROSITIES ARE DEFINED.
-------------------------------------------------------------------------
--

INIT

--      ARRAY   VALUE     ------- BOX ------
EQUALS

      'DX'     100      /
      'DY'     100      /
      'PORO'   0.3       /

      'DZ'     20        1 15  1 15  1 1  /
      'PERMX'  50       /
      'MULTZ'  0.64      /
      'TOPS'   4200      /

      'DZ'     20        1 15  1 15  2 10  /
      'PERMX'  50       /
      'MULTZ'  0.64      /
/        EQUALS IS TERMINATED BY A NULL RECORD

-- THE Y AND Z DIRECTION PERMEABILITIES ARE COPIED FROM PERMX
--     SOURCE   DESTINATION   ------- BOX ------
COPY
      'PERMX'     'PERMY'    1  15  1  15  1  10  /
      'PERMX'     'PERMZ'    /
/
-- OUTPUT OF DX, DY, DZ, PERMX, PERMY, PERMZ, MULTZ, PORO AND TOPS DATA
-- IS REQUESTED, AND OF THE CALCULATED PORE VOLUMES AND X, Y AND Z
-- TRANSMISSIBILITIES
RPTGRID
  1  1  1  1  1  1  0  0  1  1  0  1  1  0  1  1  1 /
```

PROPS

```
PROPS    ==============================================================

--
--   SWAT    KRW    PCOW
--
SWFN
    0.12   0        0
    1.0    0.1      0   /
/

--
--   SGAS    KRG    PCOG
--
SGFN

    0      0        0
    0.02   0        0
    0.05   0.005    0
    0.12   0.025    0
    0.2    0.075    0
    0.25   0.125    0
    0.3    0.19     0
    0.4    0.41     0
    0.45   0.6      0
    0.5    0.72     0
    0.6    0.87     0
    0.7    0.94     0
    0.85   0.98     0
    1.0    1.0      0
/
/

-- OIL RELATIVE PERMEABILITY IS TABULATED AGAINST OIL SATURATION
-- FOR OIL-WATER AND OIL-GAS-CONNATE WATER CASES
--
--   SOIL       KROW      KROG
SOF3

    0          0         0
    0.18       0         0
    0.28       0.0001    0.0001
    0.38       0.001     0.001
    0.43       0.01      0.01
    0.48       0.021     0.021
    0.58       0.09      0.09
    0.63       0.2       0.2
    0.68       0.35      0.35
    0.76       0.7       0.7
    0.83       0.98      0.98
```

```
--
--     REF. PRES. REF. FVF  COMPRESSIBILITY  REF VISCOSITY  VISCOSIBILITY
--
PVTW
        2014.7     1.029        3.13D-6           0.31             0 /

--
--     REF. PRES   COMPRESSIBILITY
--
ROCK
         14.7           3.0D-6           /

--
-- SURFACE DENSITIES OF RESERVOIR FLUIDS
--
--          OIL    WATER   GAS
DENSITY
           49.1    64.79  0.06054   /

--
--    PGAS    BGAS    VISGAS
PVDG
     14.7   100.0     0.0151
    284.7    62.4     0.0160
    562.7    30.5     0.0163
    831.7    19.9     0.0165
   1091.7    14.7     0.0168
   1346.7    11.6     0.0171
   4014.7     0.811   0.0268
   5014.7     0.649   0.0309
   9014.7     0.386   0.047    /


--
--    RS       POIL   FVFO   VISO
PVTO

    0.001     14.7  1.050   2.04    /
    0.283    284.7  1.1310  1.92    /
    0.575    562.7  1.2144  1.86    /
    0.858    831.7  1.2951  1.8     /
    1.131   1091.7  1.3731  1.72    /
    1.400   1346.7  1.4500  1.65
            4014.7  1.3728  2.61    /
/
```

PROPS (cont)

```
--
-- FOAM ADSOPTION ISOTHERMS
--
FOAMADS
 0.0      0.00000
 1.0      0.00005
30.0      0.00005  /

 0.0      0.00000
 1.0      0.00002
30.0      0.00002  /

--
-- ROCK DENSITY AND ADSORPTION MODEL
--
FOAMROCK
 1   2650 /
 2   2650 /

--
--   FOAM DECAY DATAAS AS FUNCTION OF WATER SATURATION
--
FOAMDCYW
 0.0 3000
 1.0 2000 /

 0.0 3000
 1.0 2000 /

--
--   FOAM DECAY DATA AS A FUNCTION OF OIL SATURATION
--
FOAMDCYO
 0.0 3000.0
 1.0 2500.0   /

 0.0 3000.0
 1.0 2500.0   /


--
--   FOAM MOBILITY REDUCTION
--
FOAMMOB
  0       1
  0.001   0.4
  0.1     0.1
  1.2     0.05    /
```

```
--
--   PRESSURE EFFECT ON THE MOBILITY REDUCTION
--   IN THIS CASE HIGHER PRESSURE REDUCES THE FOAM EFFECTIVENESS
--
FOAMMOBP
 3000 0
 6000 0.2   /

--
--   SHEAR RATE EFFECT ON THE MOBILITY
--   IN THIS CASE HIGH SHEAR REDUCES THE FOAM EFFECTIVENESS
--
FOAMMOBS
 0.0 0
 4.0 0.1    /


--
-- OUTPUT CONTROLS FOR PROPS DATA
--
RPTPROPS
 'FOAM'   /



REGIONS

EQUALS
 'SATNUM' 1 /
 'FIPNUM' 1 /
 'SATNUM' 2   1 3  1 3  1 3 /
 'FIPNUM' 2   1 3  1 3  1 3 /
/
```

SOLUTION

```
SOLUTION ===============================================================
-------- THE SOLUTION SECTION DEFINES THE INITIAL STATE OF THE SOLUTION
-------- VARIABLES (PHASE PRESSURES, SATURATIONS AND GAS-OIL RATIOS)
------------------------------------------------------------------------
-- DATA FOR INITIALISING FLUIDS TO POTENTIAL EQUILIBRIUM
--
--    DATUM  DATUM   OWC    OWC    GOC    GOC    RSVD   RVVD   SOLN
--    DEPTH  PRESS  DEPTH   PCOW  DEPTH   PCOG  TABLE  TABLE   METH
EQUIL
       4265   1854   4455    0     4173    0      1      0       0  /

-- VARIATION OF INITIAL RS WITH DEPTH
--
--    DEPTH    RS
RSVD
       4173  1.400
       4455  1.400  /

--
-- OUTPUT CONTROLS
--
RPTSOL
   'PRESSURE' 'SWAT' 'SGAS' 'FOAM' /
```

SUMMARY

```
SUMMARY  ==============================================================
-------- THIS SECTION SPECIFIES DATA TO BE WRITTEN TO THE SUMMARY FILES
-------- AND WHICH MAY LATER BE USED WITH THE ECLIPSE GRAPHICS PACKAGE
-----------------------------------------------------------------------

--REQUEST PRINTED OUTPUT OF SUMMARY FILE DATA

RUNSUM
SEPARATE

-- FIELD OIL PRODUCTION
FOPR
FOPT
FOE
FPR

-- WELL GAS-OIL RATIO FOR PRODUCER
WGOR
'PRODUCER'
/

WWCT
'PRODUCER'
/

-- WELL BOTTOM-HOLE PRESSURE

WBHP
'PRODUCER'
/

-- SATURATIONS IN INJECTION AND PRODUCTION CELL
BGSAT
10 10 3
1  1  1
/

BOSAT
10 10 3
1  1  1
/

BWSAT
10 10 3
1  1  1
/
```

```
-- PRESSURE IN INJECTION AND PRODUCTION CELL
BPR
10 10 3
1  1  1
/

FTPRFOA
FTPTFOA
FTIRFOA
FTITFOA
FTIPTFOA
FTADSFOA
FTDCYFOA

BTCNFFOA
 1 1 1 /
 2 2 1 /
/
WTPRFOA
'OP'  /
RTIPTFOA
 1 /

BTADSFOA
 1 1 1 /
/
BTDCYFOA
 1 1 1 /
/
BTHLFFOA
 1 1 1 /
/
RTADSFOA
 1 /
RTDCYFOA
 1 /
```

SCHEDULE

```
SCHEDULE ===============================================================
-------- THE SCHEDULE SECTION DEFINES THE OPERATIONS TO BE SIMULATED
------------------------------------------------------------------------
-- CONTROLS ON OUTPUT AT EACH REPORT TIME

RPTSCHED                                          FIELD   10:29 13 JUN 85
 'PRESSURE' 'SWAT' 'SGAS' 'SOIL' 'FOAM' 'WELLS=2' 'NEWTON=2' FIPFOAM = 2
 'TRADS' 'FOAMADS' 'FOAMDCY' 'FOAMMOB' /

RPTRST
 3 0 1 0 0 2 /

-- SET 'NO RESOLUTION' OPTION
DRSDT
      0  /

-- WELL SPECIFICATION DATA
--
--      WELL    GROUP LOCATION  BHP   PI
--      NAME    NAME    I  J   DEPTH DEFN
WELSPECS
    'PRODUCER' 'G'   15 15    4200 'OIL'  /
    'INJECTOR' 'G'    1  1    4200 'GAS'  /
/

-- COMPLETION SPECIFICATION DATA
--
--      WELL      -LOCATION- OPEN/ SAT CONN  WELL
--      NAME      I  J K1 K2 SHUT  TAB FACT  DIAM
COMPDAT
    'PRODUCER'  15 15 1  1 'OPEN' 0   -1    0.5  /
    'INJECTOR'   1  1 1  1 'OPEN' 1   -1    0.5  /
  /

--
-- PRODUCTION WELL CONTROLS
--
--       WELL     OPEN/  CNTL   OIL  WATER   GAS  LIQU   RES   BHP
--       NAME     SHUT   MODE  RATE   RATE  RATE  RATE  RATE
WCONPROD
     'PRODUCER' 'OPEN' 'ORAT' 1500   /
  /
```

```
--
-- INJECTION WELL CONTROLS
--
--      WELL     INJ   OPEN/  CNTL    FLOW
--      NAME    TYPE   SHUT   MODE    RATE
WCONINJE
     'INJECTOR' 'GAS' 'OPEN' 'RATE'  0  /
  /

TSTEP
 1 3*100 /

WCONINJE
     'INJECTOR' 'GAS' 'OPEN' 'RATE'  800  /
  /

--
-- SPECIFY THE FOAM INJECTOR
--
WFOAM
 'INJECTOR'  5 /
/

TSTEP
 1 70*100 /

END
```